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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-01933A-07-0402
THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	Docket No. E-01933A-05-0650

NOTICE OF FILING OF DIRECT TESTIMONY (RATE DESIGN) AND ATTACHMENTS OF KEVIN C. HIGGINS ON BEHALF OF PHELPS DODGE MINING COMPANY AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION

Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition (collectively "AECC"), hereby submits the Direct Testimony (Rate Design) and Attachments of Kevin C. Higgins on behalf of AECC in the above captioned Docket.

RESPECTFULLY SUBMITTED this 14th day of March 2008.

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	Docket No. E-01933A-07-0402
IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103	)	Docket No. E-01933A-05-0650

Direct Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice and Competition

Rate Design

March 14, 2008

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

I. Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who filed direct testimony in the revenue requirement phase of this proceeding on behalf of Phelps Dodge Mining Company ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC")?

A. Yes, I am.

II. Overview and Conclusions

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My testimony addresses several cost-of-service and rate design issues in TEP's general rate case filing, and recommends changes to TEP's proposed rate design in support of a just and reasonable outcome. My testimony in this phase of the proceeding is directed to TEP's "Cost-of-Service Methodology."

Q. Please summarize your conclusions and recommendations with respect to rate design issues in this proceeding.

A. I offer the following conclusions and recommendations:

(1) In my revenue requirement testimony I concluded that TEP's proposed Termination Cost Regulatory Asset Charge ("TCRAC") is without merit and recommended that it should be rejected. Consistent with this recommendation, no TCRAC should be adopted. However, if the Commission does not accept my recommendation to reject the TCRAC, then the cents-per-kWh rate design proposed by TEP for the TCRAC should be rejected, and instead, the costs should be recovered through an equal-percentage-of-bill rider applied to all retail customers.

(2) I recommend that the Commission reject the Peak and Average Demand method that TEP proposes for the allocation of generation plant costs, as it is a conceptually-flawed approach. This method double counts average demand, resulting in a bias against higher-load-factor customers. This problem can be remedied by using the Average and Excess Demand method, which uses the same energy-based allocation that TEP is recommending for generation costs, but avoids the double-counting of average demand during the system peak.

(3) Multiple cost-of-service studies show that the General Service class is significantly over-recovering its costs under current rates (inclusive of the Fixed CTC).

(4) Both the Average and Excess Demand method and the 4CP method show the Large Light & Power class dramatically over-recovering its costs at current rates (inclusive of the Fixed CTC).

(5) TEP's use of Peak and Average Demand method for allocating transmission expense should be rejected. The FERC-approved transmission rates that TEP is charging itself for providing service to its retail customers were determined in the first instance using the 4CP method. The same 4CP method should be used for allocating transmission expense across customer classes. I recommend that the Commission order TEP to re-file its unbundled transmission rates such that: (a) transmission expense is allocated to customer classes on a 4CP basis; and (b) transmission rates for demand-billed customers are recovered solely through a demand charge, not an energy charge.

(6) TEP's distribution cost-of-service study shows that the distribution system costs attributable to the Large, Light and Power class at TEP's requested rate of return is a little over $4 million. Yet, the unbundled distribution charges TEP is proposing for these customers would recover $26.6 million – over 6.5

times the cost of providing distribution service to them. The distribution charges for this customer class should be dramatically reduced to better reflect the actual cost to provide this service.

(7) I recommend that the first $30 million of any revenue reductions ordered by the Commission (relative to the $63 million base rate increase being proposed by TEP) should be apportioned as follows: (a) $20 million reduction to the General Service class in recognition that this class is over-recovering costs under current rates; and (b) $10 million reduction to Large, Light & Power to be effected through a reduction in the unbundled distribution charge to these customers to bring these charges closer to distribution cost-of-service. If the Commission orders less than a $30 million reduction from the $63 million increase requested by TEP, then the dollar reduction should be apportioned between General Service and Large, Light & Power in this same 2:1 ratio.

(8) If the Commission orders a rate reduction that is greater than $30 million (relative to the $63 million base rate increase being proposed by TEP) then I recommend that the incremental reduction be apportioned to each customer class on an equal percentage basis (except Mines, which are presumed to be served under special contracts). In the case of Large, Light & Power, the reduction should be targeted to the unbundled distribution charge.

(9) If the Commission approves a base rate increase that is greater than $63 million, then I recommend that any incremental increase above $63 million should be apportioned to General Service and Large, Light & Power such that the incremental percentage rate increase to these classes is 50 percent of the overall retail percentage increase.

(10) I support TEP's overall move toward time-of-use rates, as this will improve price signals to customers.

(11) TEP's proposed rate design for non-residential customers is severely skewed toward energy charges and away from demand charges. For each demand-billed rate schedule, TEP should be ordered to reformulate the distribution charge such that 100 percent of the distribution rate is recovered either in the customer charge or the demand charge – with none of the recovery occurring in an energy charge. Similarly, for rate schedules that are demand-billed, a minimum of 55 percent of TEP's generation cost that is unrelated to fuel and purchased power should be recovered through a demand charge (and removed from the energy charge).

(12) TEP should be required to file an interruptible rate schedule that provides a range of options with respect to notice requirements, duration, and frequency, and which provides a credit to participating customers based on the value of the capacity expense the customer allows the utility to avoid. The

interruptible rate schedule should be developed after consultation with Staff and interested stakeholders in a collaborative process.

(13) TEP's proposal for inverted block rates for small General Service customers is misguided and should be rejected. The notion of "lifeline" rates does not translate to non-residential customers. The relative differences in electricity usage among commercial (and industrial customers) are driven largely by the differing requirements of their respective businesses, as opposed to individual consumption preferences. Applying inverted block pricing to non-residential customers simply creates a new subsidy in which the larger customers on the rate schedule pay for the energy costs of the smaller customers on the rate schedule – e.g., the grocery stores pay for the energy costs of the gas stations – without regard to the energy efficiency practices of either.

III. <u>Termination Cost Regulatory Asset Charge</u>

Q. What is the Termination Cost Regulatory Asset Charge?

A. As discussed in my revenue requirements testimony, the Termination Cost Regulatory Asset Charge ("TCRAC") is the mechanism that TEP has proposed for recovering the $788 million regulatory asset it has requested if the Cost-of-Service Methodology is adopted. TEP asserts that such a regulatory asset is necessary "in recognition of the economic burden imposed on TEP as a result of the extended rate freeze and return to full cost-of-service regulation."[1] The first year cost to TEP customers of the TCRAC would be $117.6 million.

In my revenue requirements testimony I explain why the TCRAC proposal is without merit and recommend that it be rejected.

Q. What rate design has TEP proposed for the TCRAC?

A. TEP has proposed a straight kilowatt-hour charge of 1.2622 cents/kWh applicable to all retail kilowatt-hours.

[1] Direct testimony of Kentton C. Grant, p. 2, lines 22-25.

Q. If notwithstanding your recommendation that the TCRAC be rejected, some form of the mechanism is approved by the Commission, do you believe TEP's proposed rate design should be adopted?

A. Absolutely not. TEP is attempting to recover "foregone rate increases" due to the rate cap. A straight kilowatt-hour charge is entirely inappropriate for such a purpose. There is no basis to assert that any rate increases that TEP might have "foregone" between 2003 and 2008 would have been recovered from customers on a straight kilowatt-hour basis. In fact, the likelihood of recovering a general rate increase in such a manner is almost nil. Recovering such an extraordinary cost on a straight kilowatt-hour basis would ignore relative cost-of-service among rate classes and would unfairly burden higher-load-factor customers within rate classes.

Q. If notwithstanding your recommendation that the TCRAC be rejected, some form of the mechanism is approved by the Commission, what rate design would be most appropriate?

A. If TEP is permitted some type of regulatory asset recovery such as the TCRAC in exchange for applying the Cost-of-Service Methodology to post-2008 rates, then the most reasonable mechanism for cost recovery from customers would be an equal percentage of bill rider applied to all retail customers. Such a mechanism would assess the regulatory asset burden such that it was directly proportionate to the rates that are decided in this proceeding. That is the most reasonable means for assigning responsibility for recovering any "foregone" rate increases from the past.

IV. <u>Class Cost-of-Service</u>

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- Separating the utility's costs in accordance with the various *functions* of its system (e.g., generation, [or production], transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for causing the utility's costs to the various customer classes.

Q. What is the role of cost-of-service analysis in setting rates?

A. Each of the three steps above has an important role in the ratemaking process. If rates are unbundled by function, as they are in Arizona, then separating the utility's costs by function is important in determining which costs are generation-related, transmission-related, and distribution-related.

The classification of costs is critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes is important for determining revenue apportionment across customer classes, also called "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. For these reasons, the results of the class cost-of-service analysis should be given very strong weighting in guiding the proper revenue apportionment.

A. Allocation of Generation Plant Costs

Q. What approach has TEP used for allocating generation plant costs between TEP retail customers and FERC-jurisdictional customers?

A. As explained in the direct testimony of TEP witness D. Bentley Erdwurm, TEP uses the 4-Coincident Peaks ("4CP") method for allocating generation plant costs between its state and federal jurisdictional loads. TEP's system is designed to meet peak demands in the months of June, July, August, and September. Consequently, the allocation factor for generation capacity is calculated using each jurisdiction's contribution to system peak at the time of the June, July, August, and September peaks.

Q. In your opinion, is the 4CP method appropriate for allocating TEP's generation plant costs?

A. Yes, given the characteristics of TEP's system, the 4CP method is appropriate for allocating generation plant costs. As noted by Mr. Erdwurm, the 4CP method has been accepted by FERC for application to TEP.

Q. **Does TEP also use the 4CP method for allocating generation plant costs across its retail customer classes?**

A. No. Even though TEP uses the 4CP method for allocating generation plant costs between its jurisdictions, TEP does not use this method for allocating costs across its retail customer classes. For class cost of service, TEP uses a variant of the "Peak and Average Demand" method, which Mr. Erdwurm refers to as "Average and Peaks". [2]

Q. **Are you familiar with the Peak and Average Demand method?**

A. Yes. The Peak and Average Demand method is classified in the NARUC Cost Allocation Manual as a "Judgmental Energy Weighting" approach. According to this method, fixed production cost is allocated based on a combination of each class's share of coincident peak demand, as well as each class's share of energy usage. In applying this method, class energy consumption is typically expressed as "average demand," which gives rise to the term "Peak and Average." (Average demand is simply annual energy divided by the number of hours in the year.)

Q. **In your opinion, is the Peak and Average Demand method appropriate for allocating TEP's generation plant costs?**

A. No. The Peak and Average Demand method is conceptually flawed in that average demand is already included in peak demand and is thus counted twice in the allocation of costs. This double-counting contributes to a bias against higher-load-factor customers inherent in this method. Fortunately, however, this problem

[2] "Peak and Average Demand" is the nomenclature used in the NARUC Electric Utility Cost Allocation Manual.

can be remedied by applying an alternate method that uses the same energy-based allocation that TEP is recommending, but avoids the double-counting of average demand at peak. This alternative is known as the "Average and Excess Demand" method.

Q. Before discussing this alternative approach, please explain the analytical flaw in the Peak and Average Demand method.

A. We can use a simple example to illustrate the Peak and Average Demand method and its serious flaw. Assume we have two customer classes: Flat and Peaky. To highlight the underlying drivers of the Peak and Average Demand method, let us assume that the Flat class has a constant load of 500 MW throughout the year. Let us further assume that the load pattern of the Peaky class is as follows: January-March: 300 MW; April-May: 500 MW; June: 700 MW; July-August: 800 MW; September: 700 MW; October: 500 MW; and December: 300 MW. This example is illustrated in Figure KCH-2, on the following page.

Figure KCH-2

Peak and Average Demand Method: Illustrative Example

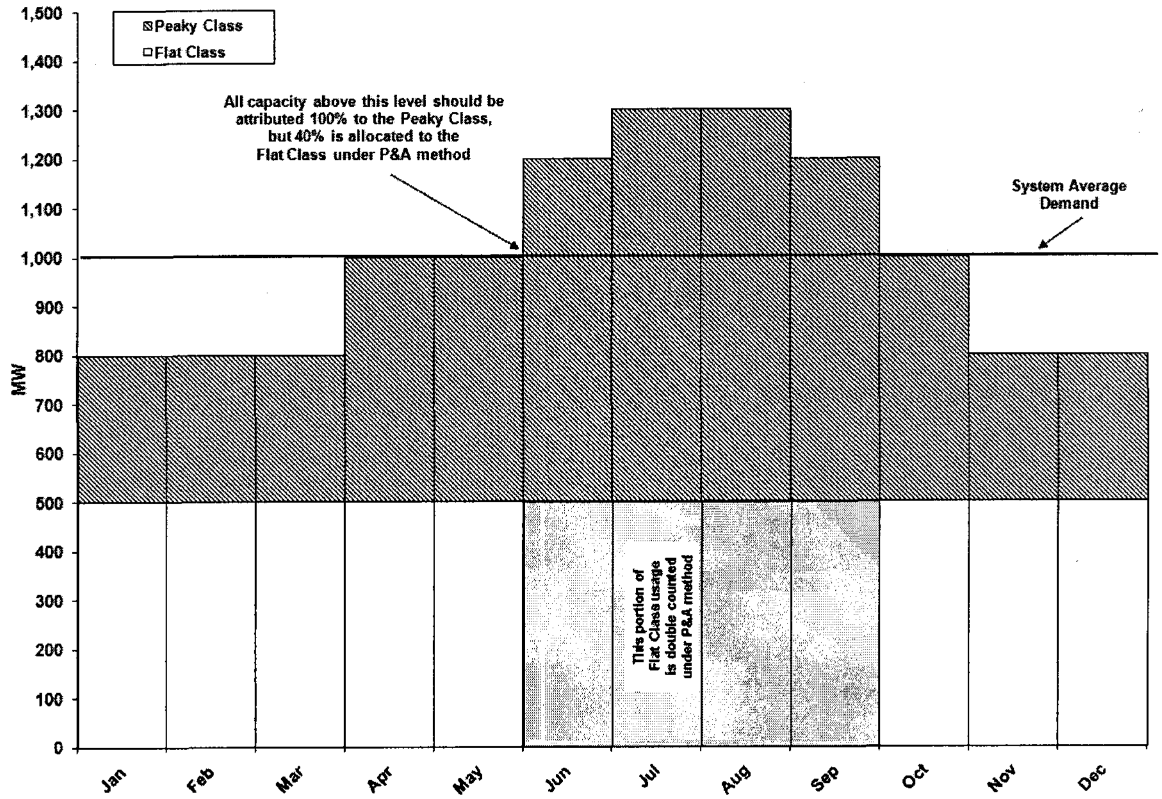

Figure KCH-2 shows the monthly demand of the Flat class at the bottom of the diagram. The monthly demand of the Peaky class is stacked on top of the Flat class's demand, such that the sum of the two constitutes the total demand for the system. The average demand of each of these classes is 500 MW, resulting in an average demand for this two-class system of 1000 MW. Accordingly, the Peak and Average Demand method will allocate each of these classes 50 percent of the responsibility for the energy, or average demand, portion of costs.

The system peak demand averages 1250 MW in the four summer months, June through September. It is clear in this example that all of the incremental capacity required above the system average of 1000 MW demand is attributable to the needs of the Peaky class – after all, the load of the Flat class is, of course, flat. But the Peak and Average Demand method will not allocate the full cost of this incremental capacity to the Peaky class. Instead, it will allocate these incremental costs in accordance with the share of each class's demand during the peak summer months; that is, the Flat class will be allocated 40% of the incremental cost (500 MW/1250 MW) and the Peaky class will be allocated 60% of the incremental cost. Put another way, even though all of the Flat class's usage during the summer has already been accounted for in the allocation of average demand, the Flat class will be allocated an additional 40% of the costs of the incremental capacity above system average demand when the summer peak demand is apportioned. This additional allocation occurs because the Peak and Average Demand method allocates capacity costs based on total demand during the summer – not just the excess above average demand, even though average demand has already been fully allocated in the first step. This additional allocation is the double-weighting to which I referred previously in my testimony. In my opinion, this double-weighting amounts to a serious analytical flaw in the Peak and Average Demand method.

Q. Has the Commission expressed concern about the use of the Peak and Average Demand method?

A. Yes. In Decision No. 69663 issued June 28, 2007, the Commission addressed Staff's recommended use of the Peak and Average Demand method in the Arizona Public Service Company ("APS") rate case. APS had used the 4CP method. The Commission stated:

> We agree with Staff that an energy-weighting method for allocating production plant is appropriate for APS. However, we are not convinced that the method recommended by Staff is the method that should be adopted. AECC's recommended Average and Excess Demand method would eliminate the criticism that the average demand is being counted twice. [Decision No. 69663, p. 70, line 27 – p. 71, line 2.]

Q. Does the Average and Excess Demand method avoid the double-weighting of average demand costs?

A. Yes. The Average and Excess Demand method avoids the problem of double-weighting while using the same allocation treatment of energy, or average demand, as the Peak and Average Demand method: the difference is in the treatment of the incremental capacity requirements above average demand.

The Average and Excess Demand method is described in the NARUC Manual in its section entitled "Energy Weighting Methods." This method has the virtue of meeting the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[3] At the same time, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

Q. How does the Average and Excess Demand method apportion responsibility for incremental production plant that is required to meet loads that are above average demand?

A. The Average and Excess Demand method allocates the cost of capacity above average demand in proportion to each class's <u>excess</u> demand, where excess demand is measured as the difference between each class's individual peak demand[4] and its average demand. By focusing on excess demand, this method avoids the double-weighting of average demand that occurs in the Peak and Average Demand method.

Q. How would the Average and Excess Demand method allocate the capacity above average demand in your illustrative example?

A. The capacity above average demand would be allocated in proportion to each class's share of excess demand. In this example, the peak demand of the Flat class is the same as its average demand; that is, its excess demand is zero. The peak for the Peaky class is 800 MW, which translates into a class excess demand of 300 MW (i.e., 800 MW - 500 MW), which, of course, is also the entirety of the excess demand on this system. Thus, the Peaky class is allocated all of the cost associated with incremental capacity above average demand. Put another way, the Average and Excess Demand method properly assigns the cost of the incremental amount of production plant used to serve system requirements above average demand.

Q. Is the Average and Excess Demand method used elsewhere in this region of the country?

A. Yes. This method is used by both Salt River Project and Public Service Company of Colorado.

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[3] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

Q. Has TEP prepared a class cost-of-service analysis using the Average and Excess Demand method?

A. Yes. TEP prepared a class cost-of-service study using the Average and Excess Demand method in response to DOD Data Request 6.1.

Q. Has TEP also prepared a class cost-of-service analysis using the 4CP method?

A. Yes. TEP prepared a class cost-of-service study using the 4CP method in response to DOD Data Request 3.3 (Update).

Q. Do you have any observations concerning the various cost-of-service analyses prepared by TEP?

A. Yes. Each of the cost-of-service studies performed by TEP shows the rates-of-return by customer class assuming that there are no Fixed CTC revenues (or DSM-related revenues) being recovered in current rates. For example, TEP's Schedule G-1, which summarizes the Company's Peak and Average Demand cost-of-service study, shows Total TEP operating income of <u>negative</u> $13.2 million. It also shows negative returns for each rate class except General Service and Lighting. These negative returns are only appearing in Schedule G-1 because TEP removed $89.6 million in Fixed CTC revenues from rates for this analysis. But of course, customers are still paying these charges, so the rates of return that appear in Schedule G-1 – or any of TEP's cost-of-service studies – are not very helpful upon first review. To be analytically useful, the Fixed CTC revenues (and

[4] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

DSM-related revenues) must be restored and attributed to the classes that are currently paying these revenues.

Q. Have you reconstructed TEP's cost-of-service results with the Fixed CTC revenues included in current rates?

A. Yes. For TEP's Peak and Average Demand study (Schedule G-1), the results are reconstructed in Schedule KCH-7, page 1. This schedule shows a Total TEP operating income of $44.3 million. The class rates of return appearing in line 25 should be interpreted as the returns derived using TEP's Peak and Average Demand study with the Fixed CTC and DSM revenues <u>in</u> current rates.

Q. Do you have any other observations concerning TEP's cost-of-service results?

A. Yes. Apparently TEP conducted its class cost-of-service study for a different test period than was used for revenue requirement. The test period for class cost-of-service is the year ending June 30, 2006, whereas the test period for revenue requirement is for the year ending December 31, 2006.

Q. Does the use of the test period ending June 30, 2006 instead of December 31, 2006 have much impact on the study results?

A. Apparently, yes. In TEP's Response to DOD Data Request 3.2, TEP reran its Peak and Average Demand study for the test period that coincides with the test period used for revenue requirement – the year ending December 31, 2006. In Schedule KCH-7, page 2, I have reconstructed TEP's results with Fixed CTC revenues (plus DSM-related revenues) included in current rates. The results show that the rate of return for the Large Light & Power class is considerably higher using the test period ending December 31, 2006 than for the test period ending June 30, 2006.

Q. Do you have any other observations concerning TEP's cost-of-service results?

A. The results for the Mines class need to be viewed with some caution. TEP's cost-of-service study shows this class as under-recovering, but current revenues for this class do not reflect the rate changes for mining customers that will be in effect in 2009. In Decision No. 69873, issued August 28, 2007, the Commission approved a new special contract for one major mining customer, the pricing terms of which are confidential. The special contract for the other mining customer expires at the end of 2008 and this customer's rates in the rate effective period will undoubtedly be different than those reflected in TEP's cost-of-service studies. Any increased revenues that TEP will receive from charging higher rates to customers in the Mines class in the rate effective period will contribute to the recovery of TEP's target revenue requirement. TEP's filing does not currently reflect these additional revenues.

Q. Have you reconstructed TEP's cost-of-service results for the Average and Excess Demand and 4CP methods with the Fixed CTC revenues included in current rates?

A. Yes. These results are shown in Schedule KCH-7, pages 3 and 4. Table KCH-1, below, summarizes the class rates of return that appear in Schedule KCH-7.

Table KCH-1

Class Rates of Return Using Different CCOS Methods
(Fixed CTC included in current revenues)

CCOS Method	Total	Res	GS	LL&P	Mines	Lighting	Pub Auth
Peak & Average (6/06)	4.50%	1.12%	13.88%	-2.84%	-25.68%	3.22%	-2.03%
Peak & Average (12/06)	4.50%	0.23%	14.11%	6.18%	-22.03%	6.94%	-11.83%
Average & Excess Dem.	4.50%	-2.15%	13.26%	20.20%	4.08%	-9.27%	6.51%
4 CP	4.50%	-1.82%	13.04%	26.33%	6.90%	13.36%	-16.70%

Q. What observations do you draw from the results of the Average and Excess Demand and 4CP methods?

A. Both the Average and Excess Demand method and the 4CP method show the Large Light & Power class dramatically over-recovering its costs at current rates (inclusive of the Fixed CTC).

Q. Do you have any observations concerning the study results for the General Service class?

A. Yes. Each cost-of-service study shows that the General Service class is significantly over-recovering its costs under current rates (inclusive of the Fixed CTC).

Q. What conclusions do you draw concerning the use of these cost-of-service results for the determination of rate spread in this proceeding?

A. There are at least two key insights that stand out from these results. First, any rate spread should recognize that the General Service class is already paying rates that are too high even if TEP received the full $63 million rate increase it is requesting under the Cost-of-Service Methodology (not counting the TCRAC). Secondly, under the more commonly-utilized CP and Average and Excess

Demand cost allocation methods, the Large Light & Power class is significantly over-recovering. I will present additional information on this issue when I discuss distribution cost-of-service later in this Section IV.

I will present my overall rate spread recommendations in Section V of my testimony.

B. Allocation of Transmission Expense and Transmission Rate Design

Q. What has TEP proposed with respect to the allocation of transmission expense?

A. Transmission expense is an unbundled rate component in TEP's tariff. TEP has proposed that transmission expense be allocated to customer classes using the same Peak and Average Demand method the Company uses for allocating generation plant costs.

Q. What is your assessment of TEP's approach to allocating transmission expense?

A. As I explained above, the use of the Peak and Average Demand method for allocating generation plant costs is highly flawed. The method is even more inappropriate for allocating transmission expense, as there is no transmission equivalent to base load generation plant to justify the use of Average Demand as an allocator. The use of Peak and Average Demand method for allocating transmission expense should be soundly rejected.

The FERC-approved transmission rates that TEP is charging itself for providing service to its retail customers were determined in the first instance using the 4CP method. The same 4CP method should be used for allocating transmission expense across customer classes.

Q. Have you performed an allocation of transmission expense using the 4CP method?

A. Yes, I have. This analysis is presented in Schedule KCH-8.

Q. Do you have any other comments concerning transmission rates?

A. Yes. TEP is proposing to recover transmission expense on a cents-per-kWh basis. Such a rate design for transmission service is entirely inappropriate for demand-metered customers. Transmission service is inherently capacity-related and transmission rates should be designed on a dollars-per-kW of monthly demand basis, which is how TEP's FERC-approved transmission rates are designed. Failure to design transmission rates on a demand-billed basis will unfairly shift transmission costs within demand-billed rate schedules from lower-load-factor customers (whose use of the transmission system is relatively "peaky") to higher-load-factor customers (whose use of the transmission system is relatively constant).

In Schedule KCH-8, I present re-designed transmission rates by customer class using TEP's proposed transmission expense.

Q. What transmission rate design is utilized by APS?

A. This issue was addressed in the most recent APS rate case. As a result of that proceeding, APS changed its transmission rate design from a cents-per-kWh charge to a dollars-per-kW-month charge for demand-billed customers, just as I am recommending here.

Q. Please summarize your recommendations concerning transmission cost allocation and rate design.

A. I recommend that the Commission order TEP to re-file its unbundled transmission rates such that: (1) transmission expense is allocated to customer classes on a 4CP basis; and (2) transmission rates for demand-billed customers are collected solely through a demand charge, not an energy charge.

C. Allocation and Recovery of Distribution Costs for Large, Light & Power

Q. What is the function of the utility's distribution system?

A. The distribution system delivers power from the high-voltage transmission system to the customer's meter.

Q. Are there issues concerning the allocation of distribution costs that you wish to discuss?

A. Yes. TEP's distribution cost-of-service study shows that the distribution system costs attributable to the Large, Light and Power class at TEP's requested rate of return is slightly more than $4 million.[5] Distribution costs for these customers are relatively modest, since they take service at 46,000 volts or greater, and therefore do not use the lower-voltage portion of the distribution system.

Yet, the unbundled distribution charges being levied on these customers is orders of magnitude greater than the cost to provide distribution service to these customers. As shown in Exhibit KCH-9, TEP's proposed distribution rates would

[5] TEP Schedule G-6 (Unit Costs), page 1, column 4, line 11.

recover $26.6 million from these customers – over 6.5 times the cost of providing distribution service to them. These charges are way out of line, and are well above what utilities typically charge high-voltage customers for distribution service.

Q. What do you recommend with respect to the distribution charges for the Large, Light and Power class?

A. The distribution charges for the Large, Light and Power customers should be dramatically reduced to better reflect the actual cost to provide this service. I will make a specific recommendation in this regard in the rate spread portion of my testimony which follows in Section V.

V. Rate Spread

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining rate spread, or revenue apportionment, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. What rate spread has TEP recommended for its Cost-of-Service Methodology?

A. TEP's proposed rate spread is shown in Table KCH-2, below. This table shows TEP's recommended rate spread both with and without the Company's proposed TCRAC. In both cases, the rate changes are measured from the baseline that includes the Fixed CTC and DSM-related revenues in current rates.

Table KCH-2

TEP's Proposed Rate Spread
Cost-of-Service Methodology

Customer Class	Base Rate Increase[6]		Increase w/ TCRAC[7]	
	$000	%	$000	%
Residential	$34,862	9.90%	$83,638	23.75%
General Service	$20,843	6.92%	$62,677	20.81%
LL&P	$ 5,057	7.46%	$17,035	25.14%
Mines	$ 0	0.00%[8]	$11,674	26.70%
Lighting	$ 130	2.36%	$ 648	11.72%
Public Authorities	$ 2,199	13.55%	$ 5,042	31.06%
Total Retail	$63,091	8.02%	$180,714	22.98%

Q. What are your recommendations concerning rate spread?

A. Let me start with the Company's TCRAC proposal. As I discussed above, I recommend that the TCRAC proposal be rejected. However, if some portion of the TCRAC is adopted then it should be spread to customer classes on an equal percentage of bill rider applied to all retail customers.

[6] Source: TEP Schedule H-1
[7] Source: TEP Schedule H-1 TRCAC
[8] See previous discussion on Mines class in Section IV.C of this testimony.

Turning to base rates, there is strong evidence in this proceeding that base rates should be reduced from their current levels; consequently, I do not expect the 8.02% base rate increase proposed by TEP to prevail. Therefore, my rate spread recommendation with respect to base rates addresses how best to implement any reductions from the $63 million base rate increase being requested by TEP.

Q. Please proceed.

A. I recommend that the first $30 million of any reductions ordered by the Commission relative to the $63 million base rate increase being proposed by TEP should be apportioned as follows: (1) $20 million reduction to the General Service class in recognition that this class is over-recovering costs under current rates; and (2) $10 million reduction to Large, Light & Power to be effected through a reduction in the unbundled distribution charge to these customers to bring these charges closer to distribution cost-of-service. If the Commission orders less than a $30 million reduction from the $63 million increase requested by TEP, then the dollar reduction should be apportioned between General Service and Large, Light & Power in this same 2:1 ratio.

If the Commission orders a rate reduction that is greater than $30 million (relative to the $63 million base rate increase being proposed by TEP) then I recommend that the incremental reduction be apportioned to each customer class on an equal percentage basis (except Mines, which are presumed to be served under special contracts). In the case of Large, Light & Power, the reduction should be targeted to the unbundled distribution charge.

Q. Can you provide a simple example of how this rate spread approach would work?

A. Yes. I have prepared an example in Schedule KCH-10 that assumes the Commission reduces TEP's $63 million base rate increase by $63 million – effectively holding overall revenues constant.

In this example, the first $30 million of the reduction is apportioned between General Service and Large, Light & Power as described above. The remaining $33 million reduction is apportioned to each customer class (except Mines) on an equal percentage basis. Thus, each customer class (except Mines) would experience a 4.46 percent revenue reduction in addition to any reduction awarded as part of the first $30 million reduction.

Q. What do you recommend if base rates are increased in an amount greater than the $63 million requested by TEP?

A While I do not believe this scenario is likely, it is technically possible as TEP has not yet updated the fuel and purchased power portion of its revenue requirement. If the Commission approves a base rate increase that is greater than $63 million, then I recommend that any incremental increase above $63 million should be apportioned to General Service and Large, Light & Power such that the incremental percentage rate increase to these classes is 50 percent of the overall retail percentage increase. This apportionment is in recognition of the cost-of-service issues discussed above.

VI. Rate Design

Q. What is your overall assessment of TEP's proposed rate design?

A. I support TEP's overall move toward time-of-use ("TOU") rates. TOU rates improve price signals to customers. At the same time, there are serious problems with TEP's proposed rate design for non-residential customers: namely, TEP is placing far too much of its cost recovery in energy charges and not enough in demand charges. The result is to create an unfair burden on higher-load-factor customers. I also believe that TEP's tariff is lacking in that it does not provide an option for interruptible rates. Interruptible rates provide a valuable tool for utilities in meeting system demand and can be a valuable pricing option to customers as well. Finally, I believe that TEP's proposal for inverted block rates for small General Service customers is misguided and should be rejected.

Q. Please proceed. Why do you support TEP's move toward greater applicability of TOU rates?

A. Energy costs vary across the hours of the day, with the most expensive hours typically occurring from the afternoon to the evening in summer. Designing the energy price to end-use customers to reflect variations in energy costs sends the proper signal to customers regarding the relative cost to operate the system during the peak, shoulder, and off-peak hours. Customers would then use this pricing information to alter their discretionary patterns of usage, increasing efficiency and lowering the overall cost of energy to the system.

Q. Are there other reasons besides economic efficiency to make TOU rates more widely available to customers?

A. Yes. In addition to providing these customers with an incentive to better respond to price signals, TOU rates will ensure that these customers pay rates that are more closely aligned with the costs they cause. Basic fairness dictates that customers whose patterns of energy consumption are less expensive to serve because of their load pattern should see that lower cost reflected in their bills.

Q. Does the Energy Policy Act of 2005 require utilities to expand the availability of TOU rates?

A. Yes. Section 1252 of the Act contains a passage that states as follows:

> Not later than 18 months after the date of the enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.[9]

The increased application of TOU rates in TEP's service territory helps to address these requirements.

Q. Turning now to the issue of TEP's demand and energy charges, please explain your concerns.

A. Demand-related costs are those costs that are incurred by a utility to meet customer peak, customer-class-peak and/or system peak requirements. All but the smallest of non-residential customers are billed both for the demand they require (maximum load in the billing cycle) and the energy they consume (kilowatt-hours of consumption).

TEP's proposed rate design is severely skewed toward energy charges and away from demand charges. For example, TEP is proposing to recover a significant portion of its distribution costs through energy charges. For customers who are billed on a demand-basis, this design is entirely inappropriate. Distribution costs are customer-related and demand-related – they are not energy-related. There is a strong consensus on this point. For example, in discussing distribution cost of service, the NARUC Cost Allocation Manual states: "…[A]ll costs of service can be identified as energy-related, demand-related, or customer-related. <u>Because there is no energy component of distribution-related costs, we need to consider only the demand and customer components</u>." [10] [Emphasis added]

Q. From a customer's perspective, why should it matter if TEP proposes a rate design that does not fully recover its demand-related <u>costs</u> through demand-related <u>charges</u>?

A. If a utility proposes demand-related charges that are below the cost of demand, it is going to seek to recover its class revenue requirement by over-recovering its costs in another area, most typically through levying an energy charge that is above unit energy costs, which is the case here. For a given rate schedule, when demand-related charges are set below demand-related cost, and the energy charges are set above energy cost, those customers with relatively-

[9] Energy Policy Act of 2005, Sec. 1252. I note that this section also requires state regulatory authorities to conduct an investigation and issue a decision as to whether it is appropriate to implement these and other standards in the Act.
[10] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 89.

higher load factors are forced to subsidize the costs of the lower-load-factor customers within the rate class.

Q. Why is it important for rate design to be representative of underlying cost causation?

A. Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals. For example, setting demand-related charges below the cost of demand understates the economic cost of demand-related assets, which in turn distorts consumption decisions, and calls forth a greater level of investment in fixed assets than is economically desirable.

At the same time, aligning rate design with underlying cost causation is important for ensuring equity among customers, because properly aligning charges with costs minimizes cross-subsidies among customers. As I stated above, if demand costs are understated in utility rates, the costs are made up elsewhere – typically in energy rates. When this happens, higher-load-factor customers (who use fixed assets relatively efficiently through relatively constant energy usage) are forced to pay the demand-related costs of lower-load-factor customers through the energy charge. This amounts to a cross-subsidy that is fundamentally inequitable.

Q. What do you recommend with respect to the rate design of TEP's distribution charges?

A. For each demand-billed rate schedule, TEP should be ordered to reformulate the distribution charge such that 100 percent of the distribution rate is recovered either in the customer charge or the demand charge – with none of the recovery occurring in an energy charge. Further, in so doing, none of the energy charges removed from the distribution rate should be shifted to other unbundled components.

Q. Do you have any additional comments with respect to TEP's treatment of demand and energy charges?

A. Yes. My criticism of TEP's skewing of its rate design toward energy is also applicable to TEP's proposed transmission and generation rates. My recommendation with respect to transmission rate design was discussed in Section IV.B, above. In the case of generation rates, TEP proposes no demand charge to recover costs associated with generation capacity, and instead proposes to recover all of its generation-related costs through energy charges. While recovery of costs through an energy charge is entirely appropriate for fuel and purchased power costs, it is not appropriate for capacity or demand-related costs.

Q. What portion of TEP's generation cost that is unrelated to fuel and purchased power should be recovered in a demand charge?

A. Arguably, all of TEP's generation cost that is unrelated to fuel and purchased power costs should be recovered through a demand charge from those customers who are demand-billed. At a minimum, for rate schedules that are demand-billed, 55 percent of TEP's generation cost that is unrelated to fuel and purchased power should be recovered through a demand charge (and removed from the energy charge). This percentage represents the portion of TEP's generation-related demand expense that TEP allocates on a coincident-peak basis in its cost-of-service study.

Q. What do you recommend with respect to the rate design of TEP's generation charges?

A. For each demand-billed rate schedule, TEP should be ordered to reformulate the generation charge such that at least 55 percent of the generation rate unrelated to fuel and purchased power is recovered in the demand charge. Further, in so doing, none of the energy charges removed from the generation rate should be shifted to other unbundled components.

Q. Turning now to the issue of interruptible rates, what recommendation do you make to the Commission?

A. In my opinion, TEP's tariff is lacking in that it does not provide an interruptible rate schedule option. A well-designed program that offers an interruptible rate schedule can allow the utility to meet its peaking needs and/or operating reserve requirements in a manner that provides benefits to participating and non-participating customers by reducing the overall cost of capacity to the utility. Customers choosing interruptible service should receive a credit based on the value of the capacity expense they allow the utility to avoid. The credit would be commensurate with the terms under which the customer agrees to be interrupted, e.g., length of advance notice required, duration, and frequency. A well-designed program would provide a menu of options that would allow the customer to select from among several combinations of terms.

Q. How should an interruptible credit be valued?

A. As I stated, the value of the credit would depend on the terms of interruption. A potential benchmark for measuring interruption value is the $7.00

per kW-month market-based capacity charge that TEP is proposing for its Luna Energy Facility.

Q. What is your recommendation to the Commission on interruptible rates?

A. TEP should be required to file an interruptible rate schedule that provides a range of options with respect to notice requirements, duration, and frequency, and which provides a credit to participating customers based on the value of the capacity expense the customer allows the utility to avoid. The interruptible rate schedule should be developed after consultation with Staff and interested stakeholders in a collaborative process.

Q. Turning now to the issue of inverted block rates for small General Service customers, what has TEP proposed in that regard?

A. TEP has proposed inverted block rates for small General Service customers, i.e., customers taking service on Schedules GS-10 and GS-76N. With inverted block rates, energy charges increase as energy usage increases.

Q. What is your assessment of inverted block rates for non-residential customers?

A. Inverted block rates for non-residential customers is a misguided notion and entirely inappropriate. This proposal should be rejected.

Q. Please explain.

A. The premise behind inverted block rates is that it is important to send a price signal to customers that increasing energy usage is costly to the utility system. This concept is then paired with the notion that there is a critical minimum amount of electric power that is necessary to meet basic needs. The rate design that results from combining these ideas is one in which the initial pricing block (corresponding to the first energy used in the billing period) is priced at a relatively low rate, whereas energy consumption above this amount is priced at higher rates. For small General Service customers, TEP proposes three progressively-increasing pricing blocks.

The notion of a critical minimum or a "lifeline" amount of electric power (that is priced at a lower rate) is grounded in a value judgment about what portion of electric power consumption for a residential customer is for "necessities" (e.g., lighting) and what portion constitutes discretionary or even luxury usage (e.g., heating a hot tub) . As varied as households may be, they are more homogeneous than businesses, and I believe it is reasonable to establish prices for residential customers that distinguish between "lifeline" power consumption and discretionary or luxury usage. Consequently, inverted block rates are appropriate for residential customers.

However, the notion of "lifeline" rates does not translate to non-residential customers. <u>The relative differences in electricity usage among commercial (and industrial customers) are driven largely by the differing requirements of their respective businesses, as opposed to individual consumption preferences</u>. A grocery store might be pursuing vigorous energy efficiency measures, but still be consuming ten times the electric power of a gas station, due to the nature of the business. It is not reasonable to artificially reduce the energy rates paid by the gas station below the average cost to serve it, and then transfer the burden of meeting the revenue shortfall to the energy rate paid by the grocery store in order to send a stronger conservation price signal to the grocer. Such a pricing scheme just creates a new subsidy in which the larger customers on the rate schedule pay for the energy costs of the smaller customers on the rate schedule – without regard to the energy efficiency practices of either.

Q. What is your recommendation to the Commission on this issue?

A. Inverted block rates for non-residential customers are entirely inappropriate and should be rejected. The energy charges for small General Service customers should be allowed to vary by season and TOU, but should <u>not</u> vary by monthly consumption levels

Q. Does this conclude your direct testimony with respect to rate design?

A. Yes, it does.

Class Cost of Service Results at Present Rates Including CTC & DSM Revenues
Using TEP's Filed 4CP Peak and Average Demand Methodology
(Test Period ending June 30, 2006)

LINE NO.	SUMMARY AT PRESENT RATES WITH DSM & CTC	TOTAL TEP	RESIDENTIAL	GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING	PUBLIC AUTHORITY
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$2,115,571,068	$1,068,181,445	$759,590,412	$128,207,739	$82,733,456	$24,559,185	$52,298,831
3	RESERVE FOR DEPRECIATION	1,026,757,960	509,322,036	366,911,999	69,673,770	43,178,848	12,801,332	24,869,975
4	DEFERRED TAXES & TAX CREDITS	(165,291,330)	(83,457,906)	(59,347,432)	(10,016,977)	(6,464,034)	(1,918,830)	(4,086,151)
5	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
6	REGULATORY ASSESTS	47,455,224	27,185,764	16,533,765	1,367,569	31	1,002,665	1,365,431
7	TOTAL WORKING CAPITAL	30,273,292	14,237,525	11,033,609	2,324,715	1,786,898	204,643	685,901
8	TOTAL CUSTOMER CONTRIBUTIONS	(18,516,132)	(9,339,769)	(6,896,009)	(1,493,091)	0	(205,694)	(581,569)
9								
10	TOTAL RATE BASE	$982,734,160	$507,485,023	$354,002,346	$50,716,184	$34,877,502	$10,840,637	$24,812,468
11								
12	DEVELOPMENT OF RETURN							
13	SALES OF ELECTRICITY (Excl. DSM & CTC Rev.)	$691,451,429	$307,535,130	$274,527,876	$53,836,878	$37,790,355	$4,077,303	$13,683,888
14	DSM & CTC REVENUE	95,105,561	43,045,016	36,016,019	7,198,893	5,933,345	408,843	2,503,444
15	PPFAC	0	0	0	0	0	0	0
16	OTHER OPERATING REVENUE	21,279,733	9,464,534	8,448,721	1,656,854	1,163,015	125,481	421,128
17	TOTAL OPERATING REVENUE	$807,836,724	$360,044,680	$318,992,616	$62,692,626	$44,886,715	$4,611,627	$16,608,460
18								
19	OPERATING EXPENSES							
20	OPERATION & MAINTENANCE	$671,184,760	$308,648,012	$236,140,504	$58,446,248	$49,930,025	$3,308,685	$14,711,286
21	DEPRECIATION & AMORT EXPENSE	57,914,052	28,793,133	20,821,372	3,732,441	2,557,479	615,356	1,394,270
22	TAXES OTHER THAN INCOME TAX	29,092,144	14,850,047	10,420,251	1,687,733	1,045,047	360,280	728,785
23								
24	STATE & FEDERAL INCOME TAX	5,375,321	2,050,213	2,491,483	267,783	310,148	(22,120)	277,814
25	TOTAL OPERATING EXPENSES	763,566,277	354,341,405	269,873,610	64,134,205	53,842,700	4,262,202	17,112,156
26								
27	OPERATING INCOME	44,270,447	5,703,275	49,119,006	(1,441,579)	(8,955,985)	349,426	(503,696)
28								
29	RATE OF RETURN (PRESENT WITH DSM & CTC)	4.50%	1.12%	13.88%	-2.84%	-25.68%	3.22%	-2.03%
30								
31	INDEX RATE OF RETURN (PRESENT WITH DSM & CTC)	1.00	0.25	3.08	(0.63)	(5.70)	0.72	(0.45)

Data Sources: TEP Class Cost of Service Workpapers & TEP Schedule H-2, p. 2 of 3 (Ln 14).

Class Cost of Service Results at Present Rates Including CTC & DSM Revenues
Using Calendar Year 2006 4CP/Peak and Average Demand Methodology

LINE NO.	SUMMARY AT PRESENT RATES WITH DSM & CTC	TOTAL TEP	RESIDENTIAL	GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING	PUBLIC AUTHORITY
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$2,115,571,067	$1,095,719,785	$758,006,917	$109,819,330	$77,144,694	$21,612,990	$53,267,351
3	RESERVE FOR DEPRECIATION	1,026,757,960	522,922,828	366,581,945	59,399,688	40,262,048	11,491,172	26,100,279
4	DEFERRED TAXES & TAX CREDITS	(165,291,330)	(85,609,500)	(59,223,712)	(8,580,276)	(6,027,379)	(1,688,641)	(4,161,822)
5	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
6	REGULATORY ASSESTS	47,455,224	28,007,704	16,560,843	1,032,566	31	880,676	973,404
7	TOTAL WORKING CAPITAL	30,273,291	14,565,236	10,990,610	2,036,407	1,666,190	180,648	834,200
8	TOTAL CUSTOMER CONTRIBUTIONS	(18,516,132)	(9,790,131)	(7,022,079)	(1,129,490)	0	(155,478)	(418,954)
9								
10	TOTAL RATE BASE	$982,734,160	$519,970,266	$352,730,634	$43,778,849	$32,521,488	$9,339,023	$24,393,900
11								
12	DEVELOPMENT OF RETURN							
13	SALES OF ELECTRICITY (Excl. DSM & CTC Rev.)	$691,451,429	$307,535,130	$274,527,876	$53,836,878	$37,790,355	$4,077,303	$13,683,888
14	DSM & CTC REVENUE	95,105,561	43,045,016	36,016,019	7,198,893	5,933,345	408,843	2,503,444
15	PPFAC	0	0	0	0	0	0	0
16	OTHER OPERATING REVENUE	21,279,733	9,464,534	8,448,721	1,656,854	1,163,015	125,481	421,128
17	TOTAL OPERATING REVENUE	$807,836,724	$360,044,680	$318,992,616	$62,692,626	$44,886,715	$4,611,627	$16,608,460
18								
19	OPERATING EXPENSES							
20	OPERATION & MAINTENANCE	$671,184,760	$312,377,883	$235,512,521	$54,749,931	$48,244,692	$3,103,270	$17,196,463
21	DEPRECIATION & AMORT EXPENSE	57,914,053	29,508,837	20,767,093	3,220,523	2,384,718	544,308	1,488,574
22	TAXES OTHER THAN INCOME TAX	29,092,145	15,238,935	10,401,601	1,438,735	974,453	316,975	721,446
23								
24	STATE & FEDERAL INCOME TAX	5,375,321	1,718,452	2,541,953	579,612	447,917	(1,006)	88,394
25	TOTAL OPERATING EXPENSES	763,566,279	358,844,107	269,223,168	59,988,801	52,051,780	3,963,547	19,494,877
26								
27	OPERATING INCOME	44,270,444	1,200,573	49,769,448	2,703,825	(7,165,065)	648,080	(2,886,417)
28								
29	RATE OF RETURN (PRESENT WITH DSM & CTC)	4.50%	0.23%	14.11%	6.18%	-22.03%	6.94%	-11.83%
30								
31	INDEX RATE OF RETURN (PRESENT WITH DSM & CTC)	1.00	0.05	3.13	1.37	(4.89)	1.54	(2.63)

Data Sources: TEP Response to DOD Data Request 3.2 & TEP Schedule H-2, p. 2 of 3 (Ln 14).

Class Cost of Service Results at Present Rates Including CTC & DSM Revenues
Using Calendar Year 2006 Average & Excess Demand Methodology

LINE NO.	SUMMARY AT PRESENT RATES WITH DSM & CTC	TOTAL TEP	RESIDENTIAL	GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING	PUBLIC AUTHORITY
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$2,115,571,068	$1,135,567,813	$765,979,765	$94,661,661	$51,973,643	$26,993,737	$40,394,448
3	RESERVE FOR DEPRECIATION	1,026,757,960	543,719,692	370,743,010	51,488,833	27,125,164	14,299,408	19,381,854
4	DEFERRED TAXES & TAX CREDITS	(165,291,330)	(88,722,860)	(59,846,637)	(7,395,994)	(4,060,744)	(2,109,043)	(3,156,052)
5	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
6	REGULATORY ASSESTS	47,455,224	28,007,704	16,560,843	1,032,566	31	880,676	973,404
7	TOTAL WORKING CAPITAL	30,273,292	15,425,889	11,162,810	1,709,026	1,122,536	296,863	556,167
8	TOTAL CUSTOMER CONTRIBUTIONS	(18,516,132)	(9,790,131)	(7,022,079)	(1,129,490)	0	(155,478)	(418,954)
9								
10	TOTAL RATE BASE	$982,734,160	$536,768,723	$356,091,692	$37,388,937	$21,910,302	$11,607,347	$18,967,159
11								
12	DEVELOPMENT OF RETURN							
13	SALES OF ELECTRICITY (Excl. DSM & CTC Rev.)	$691,451,429	$307,535,130	$274,527,876	$53,836,878	$37,790,355	$4,077,303	$13,683,888
14	DSM & CTC REVENUE	95,105,561	43,045,016	36,016,019	7,198,893	5,933,345	408,843	2,503,444
15	PPFAC	0	0	0	0	0	0	0
16	OTHER OPERATING REVENUE	21,279,733	9,464,534	8,448,721	1,656,854	1,163,015	125,481	421,128
17	TOTAL OPERATING REVENUE	$807,836,724	$360,044,680	$318,992,616	$62,692,626	$44,886,715	$4,611,627	$16,608,460
18								
19	OPERATING EXPENSES							
20	OPERATION & MAINTENANCE	$671,184,760	$324,380,007	$237,913,194	$50,186,368	$40,661,680	$4,725,594	$13,317,917
21	DEPRECIATION & AMORT EXPENSE	57,914,052	30,740,629	21,013,551	2,751,965	1,606,624	710,639	1,090,643
22	TAXES OTHER THAN INCOME TAX	29,092,144	15,742,275	10,502,310	1,247,271	656,505	384,941	558,842
23								
24	STATE & FEDERAL INCOME TAX	5,375,321	736,157	2,345,413	953,264	1,068,410	(133,647)	405,725
25	TOTAL OPERATING EXPENSES	763,566,277	371,599,068	271,774,468	55,138,868	43,993,219	5,687,527	15,373,127
26								
27	OPERATING INCOME	44,270,447	(11,554,388)	47,218,147	7,553,758	893,496	(1,075,900)	1,235,333
28								
29	RATE OF RETURN (PRESENT WITH DSM & CTC)	4.50%	-2.15%	13.26%	20.20%	4.08%	-9.27%	6.51%
30								
31	INDEX RATE OF RETURN (PRESENT WITH DSM & CTC)	1.00	(0.48)	2.94	4.48	0.91	(2.06)	1.45

Data Sources: TEP Response to DOD Data Request 6.1 & TEP Schedule H-2, p. 2 of 3 (Ln 14).

Class Cost of Service Results at Present Rates Including CTC & DSM Revenues
Using Calendar Year 2006 4CP Demand Methodology

LINE NO.	SUMMARY AT PRESENT RATES WITH DSM & CTC	TOTAL TEP	RESIDENTIAL	GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING	PUBLIC AUTHORITY
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$2,115,571,067	$1,129,881,806	$768,065,463	$89,363,532	$50,218,999	$20,021,572	$58,019,695
3	RESERVE FOR DEPRECIATION	1,026,757,961	540,752,139	371,831,545	48,723,716	26,209,408	10,660,604	28,580,549
4	DEFERRED TAXES & TAX CREDITS	(165,291,330)	(88,278,607)	(60,009,595)	(6,982,047)	(3,923,652)	(1,564,302)	(4,533,127)
5	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
6	REGULATORY ASSESTS	47,455,224	28,007,704	16,560,843	1,032,566	31	880,676	973,404
7	TOTAL WORKING CAPITAL	30,273,292	15,303,080	11,207,858	1,594,596	1,084,639	146,276	936,843
8	TOTAL CUSTOMER CONTRIBUTIONS	(18,516,132)	(9,790,131)	(7,022,079)	(1,129,490)	0	(155,478)	(418,954)
9								
10	TOTAL RATE BASE	$982,734,160	$534,371,713	$356,970,945	$35,155,441	$21,170,609	$8,668,140	$26,397,312
11								
12	DEVELOPMENT OF RETURN							
13	SALES OF ELECTRICITY (Excl. DSM & CTC Rev.)	$691,451,429	$307,535,130	$274,527,876	$53,836,878	$37,790,355	$4,077,303	$13,683,888
14	DSM & CTC REVENUE	95,105,561	43,045,016	36,016,019	7,198,893	5,933,345	408,843	2,503,444
15	PPFAC	0	0	0	0	0	0	0
16	OTHER OPERATING REVENUE	21,279,733	9,464,534	8,448,721	1,656,854	1,163,015	125,481	421,128
17	TOTAL OPERATING REVENUE	$807,836,724	$360,044,680	$318,992,616	$62,692,626	$44,886,715	$4,611,627	$16,608,460
18								
19	OPERATING EXPENSES							
20	OPERATION & MAINTENANCE	$671,184,759	$322,674,425	$238,548,893	$48,582,467	$40,127,736	$2,623,575	$18,627,663
21	DEPRECIATION & AMORT EXPENSE	57,914,052	30,564,862	21,078,025	2,588,188	1,552,384	495,114	1,635,479
22	TAXES OTHER THAN INCOME TAX	29,092,145	15,670,452	10,528,655	1,180,348	634,342	296,873	781,475
23								
24	STATE & FEDERAL INCOME TAX	5,375,321	876,322	2,293,999	1,083,869	1,111,664	38,224	(28,756)
25	TOTAL OPERATING EXPENSES	763,566,277	369,786,061	272,449,572	53,434,872	43,426,126	3,453,786	21,015,861
26								
27	OPERATING INCOME	44,270,446	(9,741,381)	46,543,044	9,257,754	1,460,589	1,157,841	(4,407,401)
28								
29	RATE OF RETURN (PRESENT WITH DSM & CTC)	4.50%	-1.82%	13.04%	26.33%	6.90%	13.36%	-16.70%
30								
31	INDEX RATE OF RETURN (PRESENT WITH DSM & CTC)	1.00	(0.40)	2.89	5.85	1.53	2.97	(3.71)

Data Sources: TEP Response to DOD Data Request 3.3 (Update) & TEP Schedule H-2, p. 2 of 3 (Ln 14).

AECC Recommended Transmission Cost Allocation and Rate Design
Using 4CP Class Allocation Factor

4CP ALLOCATION FACTORS FOR TRANSMISSION

Line No.	ALLOCATION FACTOR NAME	TOTAL	RESIDENTIAL	GENERAL SERVICE Without Demand	GENERAL SERVICE With Demand	LARGE LIGHT & POWER	MINING	LIGHTING	PUBLIC AUTHORITY
1	DTEHV (4CP)	100.00%	48.371%	27.137%	10.374%	6.090%	4.533%	0.121%	3.374%
2	DPRODAN (4CP exc. R-02 & Comm.-31)	100.00%	48.316%	27.220%	10.362%	6.083%	4.528%	0.121%	3.370%

Data Source: TEP Response to DOD Data Request 3.3 (Update)

ALLOCATION OF TRANSMISSION EXPENSES USING 4CP ALLOCATION

Line No.	DESCRIPTION	TOTAL	ALLOC. FACTOR	RESIDENTIAL	GENERAL SERVICE Without Demand	GENERAL SERVICE With Demand	LARGE LIGHT & POWER	MINING	LIGHTING	PUBLIC AUTHORITY
3	Transmission	65,605,059	DTEHV	31,733,907	17,803,147	6,806,080	3,995,163	2,973,887	79,562	2,213,314
4	System control load dispatch	891,846	DPRODAN	430,903	242,762	92,417	54,249	40,381	1,080	30,054
5	Reactive supply and voltage control	3,502,127	DPRODAN	1,692,081	953,284	362,907	213,026	158,570	4,242	118,016
6	Regulation and frequency response	3,393,365	DPRODAN	1,639,532	923,679	351,636	206,410	153,646	4,111	114,351
7	Spinning reserve service	9,201,240	DPRODAN	4,445,655	2,504,592	953,475	559,689	416,617	11,146	310,067
8	Supplemental reserve service	1,500,912	DPRODAN	725,178	408,551	155,531	91,297	67,959	1,818	50,578
9	Total	84,094,549		40,667,256	22,836,015	8,722,046	5,119,833	3,811,060	101,959	2,836,380

Data Source: TEP Response to DOD Data Request 3.3 (Update) & TEP Cost of Service Rate Design Workpapers

CLASS BILLING DETERMINANT DATA

Line No.		RESIDENTIAL	GENERAL SERVICE Without Demand	GENERAL SERVICE With Demand	LARGE LIGHT & POWER	MINING	LIGHTING	PUBLIC AUTHORITY
10	Billing Determinant On-Peak Demand (kW)			3,486,095	1,686,943			
11	Billing Determinant Energy (kWh)	3,864,352,371	1,981,670,111				7,287,604	225,259,044

Data Source: TEP Cost of Service Rate Design Workpapers

DERIVATION OF TRANSMISSION CHARGES

		RESIDENTIAL	GENERAL SERVICE Without Demand	GENERAL SERVICE With Demand	LARGE LIGHT & POWER	MINING	LIGHTING	PUBLIC AUTHORITY
12	Transmission Rate ($/kW)			$2.50	$3.03			
13	Transmission Rate ($/kWh)	$0.010524	$0.011524				$0.013991	$0.012592

Large Light and Power (LLP)
Distribution Cost of Service
vs. TEP Proposed Distribution Revenues

TEP LLP Demand-Related Distribution Cost of Service

Line No.		LARGE LIGHT & POWER
1	Total Rate Base	$8,892,658
2	Claimed Rate of Return (ROR)	8.35%
3	Return Required at Claimed ROR	$742,634
4	Total Revenue Required at Claimed ROR (Before application any revenue credits)	$4,062,961

Data Source: TEP Class Cost of Service Study Workpapers

TEP Proposed LLP Distribution Delivery Revenue

Line No.	UNBUNDLED SERVICE LLP-14 (NEW TOU LLP-90N)	Adjusted Booked Billing Determinants	Proposed Rate	Proposed Revenue
5	Delivery Charge (kW)			
6	On-peak	1,323,916	$8.00	$10,591,328
7	Off-peak	1,300,999	$2.66	$3,465,861
8	Delivery Charge (kWh)			
9	Summer			
10	on-peak	63,909,719	$0.020925	$1,337,330
11	off-peak	208,213,207	$0.008425	$1,754,259
12	shoulder-peak	58,804,508	$0.011245	$661,274
13	Winter			
14	on-peak	100,230,648	$0.016955	$1,699,441
15	off-peak	182,939,210	$0.004455	$815,049
16	Total LLP-14 Delivery Charge Revenue			$20,324,543
	UNBUNDLED SERVICE LLP-90A (NEW TOU LLP-90N)			
17	Delivery Charge (kW)			
18	On-peak	82,255	$8.00	$658,040
19	Off-peak	83,087	$2.66	$221,344
20	Delivery Charge (kWh)			
21	Summer			
22	on-peak	5,084,947	$0.020925	$106,404
23	off-peak	21,333,365	$0.008425	$179,740
24	shoulder-peak	5,113,873	$0.011245	$57,507
25	Winter			
26	on-peak	10,062,643	$0.016955	$170,615
27	off-peak	20,933,777	$0.004455	$93,266
28	Total LLP-90A Delivery Charge Revenue			$1,486,916
	UNBUNDLED SERVICE LLP-90F (NEW TOU LLP-90N)			
29	Delivery Charge (kW)			
30	On-peak	280,772	$8.00	$2,246,176
31	Off-peak	283,713	$2.66	$755,811
32	Delivery Charge (kWh)			
33	Summer			
34	on-peak	16,784,212	$0.020925	$351,215
35	off-peak	64,861,794	$0.008425	$546,480
36	shoulder-peak	16,713,742	$0.011245	$187,951
37	Winter			
38	on-peak	26,993,753	$0.016955	$457,687
39	off-peak	53,360,417	$0.004455	$237,737
40	Total LLP-90F Delivery Charge Revenue			$4,783,057
41	Total Large Light & Power Delivery Charge Revenue			$26,594,516

Data Source: TEP Rate Design Workpapers

42	Distribution Delivery Charge Revenues Above Distribution Cost of Service	$22,531,555

AECC Recommended Rate Spread: Example
Assumes ACC-Ordered $63 Million Reduction in TEP's Requested Base Revenue Increase

Line No.	Pricing Plans	Adjusted Present Net Revenue "Including" DSM&CTC Revenue	TEP Proposed Net Increase	TEP Proposed Percent Increase	Step 1 AECC Recommended Reduction Spread	Step 1 Proposed Percent Change	Remaining Net Increase After Step 1	Step 2 AECC Recommended Reduction Spread	Final AECC Percent Change	Line No.
1	Residential Service	$352,160,282	$34,861,888	9.90%	$0	9.90%	$34,861,888	$19,173,802	5.44%	1
2	General Service	301,140,659	20,842,985	6.92%	(20,000,000)	0.28%	842,985	($12,572,271)	-4.17%	2
3	Large Light & Power	67,761,730	5,057,456	7.46%	(10,000,000)	-7.29%	(4,942,544)	($7,961,204)	-11.75%	3
4	Mines	43,723,700	0	0.00%	0	0.00%	0	$0	0.00%	4
5	Lighting	5,528,946	130,216	2.36%	0	2.36%	130,216	($116,088)	-2.10%	5
6	Other Public Authorities	16,230,658	2,198,807	13.55%	0	13.55%	2,198,807	$1,475,761	9.09%	6
7	Subtotal	786,545,975	63,091,352	8.02%	(30,000,000)	4.21%	33,091,352	(0)	0.00%	7
8	Other Operating Revenue	21,279,733	0	N/A	0	N/A	0	0	N/A	8
9	Total	$807,825,708	$63,091,352	7.81%	($30,000,000)	4.10%	$33,091,352	($0)	0.00%	9

Supporting Schedules
(a) H-2 (P2)